APPENDIX 1

METHODOLOGY UTILIZED FOR AES NEWENERGY ANALYSIS

This appendix will explain the methodology utilized by AES NewEnergy in its analysis. Specifically, this appendix will explain:

- Customer Account Selection Process;
- Customer Account Usage Data;
- Definition of Annual Load Factor Subclasses;
- Selection Of Specific Customer Accounts From Sub-Classes;
- Method of Analysis;
- Baseline Results;
- Estimated Annual Savings Increases/(Decreases);
- Transmission Charge Sensitivity Analysis; and
- Market Value Sensitivity Analysis.

Customer Account Selection Process

As of early July 2001, AES NewEnergy served electric energy to a total of customer accounts in the Edison service territory. In order to determine an appropriate group of specific customers, who would best represent a cross-section of AES NewEnergy's entire customer base, the customer accounts were segmented by RCDS Customer Class and by annual load factor. In addition to the RCDS Customer Class segmentation, three other specific segments possessing unique characteristics differing from the overall group of customer accounts were established. These three specific segments are identified as the Space Heat, IRMA member, and HVDS segments.

The *Space Heat* segment is defined as including those customer accounts who would normally receive a class determined CTC when choosing delivery services, but instead receive the Rider 25 class CTC (which is currently 0 for Period A) because of their former bundled rate incorporation of Rider 25. Additionally, the Space Heat segment is further defined by the type of pricing arrangement these customer accounts receive from AES NewEnergy. Each customer account in this segment receives pricing in its contract with AES NewEnergy that is a function of their former bundled rates including the Rider 25 component. It should be noted that several other customer accounts served by AES NewEnergy might have utilized Rider 25 when they were served by Edison on bundled rates. However, these customer accounts are not included in the Space Heat segment as their pricing arrangement with AES NewEnergy is not a function of their former bundled rates, including the Rider 25 component.

The *IRMA* segment is defined as including those customer accounts that again would normally receive a Class CTC but instead receive a Custom CTC calculation (as would a large customer with usage greater than 3,000 kW) due to a special provision of the Customer Choice Act.

The *HVDS* segment is defined as including those customer accounts that are currently eligible for Rider 11- High Voltage Discount who would become eligible for the newly proposed Rider HVDS - High Voltage Discount.

Each of these three additional segments has a unique situation as it relates to this delivery services tariff proceeding and therefore has been identified for analysis as a separate customer account category. In fact, the two HVDS subclasses (representing customer accounts) has been separately compared to the current delivery services tariffs.

APPENDIX 1

Customer Account Usage Data

The customer account usage data was extracted from a variety of sources. Primarily, AES NewEnergy's internal billing, accounting, and pricing data sources were utilized in obtaining the majority of the usage information. In some circumstances, the usage data was supplemented with information from the Edison PowerPath website.

Definition of Annual Load Factor Subclasses

For purposes of this analysis the annual load factor is defined as a function of the maximum annual billing demand instead of the maximum annual peak demand which may or may not occur within the defined billing demand time window. Therefore, the formula used to determine each customer account's annual billing demand load factor ("Billing Load Factor") is = Annual kWh/(Maximum Annual Billing Demand kW x 8760).

From this definition, the AES NewEnergy customer accounts were distributed into the following sub-classes within each customer account class:

Subclass A: 0% < Billing Load Factor <=15%
Subclass B: 15% < Billing Load Factor <=30%
Subclass C: 30% < Billing Load Factor <= 45%
Subclass D: 45% < Billing Load Factor <= 60%
Subclass E: 60% < Billing Load Factor <= 75%
Subclass F: 75% < Billing Load Factor

By way of example, if a customer account is identified as an RCDS Class 7 and this customer account's usage data establishes a Billing Load Factor of 50%, then that customer account would be classified as a "7D". All customer accounts were categorized based on these criteria. Table 1 shows the spectrum of AES NewEnergy's customer base used for this analysis as of July, 2001.

<u>Selection Of Specific Customer Accounts From Sub-Classes</u>

In order to represent the sub-class in the most accurate manner, the customer account whose Billing Load Factor was closest to the mid-point of the sub-class definition range was selected. By way of example, the "B" defined sub-class range has a mid-point of 22.5%. The customer account in sub-class 5B, which has a Billing Load Factor that most closely approaches 22.5%, is an account with a Billing Load Factor of 22.1%. This account was selected to represent the customer accounts that reside in sub-class 5B. In a similar manner, this same approach was used in order to identify the proper customer accounts to use in this analysis.

Several special situations occurred during the customer account selection process. First, all customer accounts in sub-class 3D and customer accounts in sub-class 3E are members of IRMA and benefit from the custom CTC calculation described above. Therefore, we decided to utilize the respective sub-classes 3D and 3E customer accounts to represent the unique economic situation presented by this circumstance.

Additionally, the single (1) customer account in sub-class 2D and the two (2) customer accounts in sub-class 4F are also IRMA members. These customer account sub-classes were <u>not</u> selected individually for further analysis as the 3D and 3E customer accounts (respectively) were regarded as representative of the economic situation presented by the IRMA custom CTC arrangement.

Finally, it should be noted that in a couple of other sub-classes, the customer account whose Billing Load Factor most closely approached the mid-point of the defined range happened to be another IRMA member. In these cases, the customer account with the closest Billing Load Factor to the mid-point who was <u>not</u> an IRMA member was selected instead. This was done to more closely demonstrate the effects on the more typical customers in these sub-classes who do receive the class defined CTC's as opposed to the IRMA members who receive the benefit of custom CTC calculations and are already represented by the analysis of the 3D and 3E customer accounts analysis.

Method of Analysis

The bundled rate for each selected customer account was determined based on the appropriate bundled rate class for the account if the customer account were to return to bundled service. The respective bundled rates chosen for comparative purposes are shown in Table 2. In the case of the two (2) customer accounts analyzed in the HVDS sub-classes (HVDS-E and HVDS-F), the Rate 6L bundled calculation includes the addition of Rider 11 (High Voltage Discount) which is currently in effect. In the case of the three (3) Space Heat customer accounts analyzed (SH-B, SH-C, and SH-D), the provisions of Rider 25 were also taken into consideration for the bundled rate calculation.

The current delivery services tariff economics were evaluated using the existing delivery services tariffs and rates, the current PPO Period A MVEC's, the current Period A CTC's, and the current PPO transmission charges for each of the respective customer accounts selected for evaluation. All analysis performed was based on a 12-month period. The cost components that comprise the PPO were selected as a comparative and familiar benchmark as a measurement of how the proposed delivery services tariff changes will affect customers who have chosen delivery services rates rather than bundled rates.

Market Values

The market values derived by Edison as shown in Exhibit 13 – Attachment F were used in this analysis. It is my understanding that these MVEC's (which are slightly lower than the current Period A MVEC's) are based on the same set of "market snapshots" that were used to create the current Period A MVEC's that are now in effect.

Customer Transition Charges

The class CTC's produced by Edison in Exhibit 13 – Attachment G were used in this comparative analysis.

Selected customer accounts were submitted to the Edison Rate Department for determination of Custom CTC values based on the *proposed* delivery services tariff rates and costs.

Transmission Charges

This analysis utilized the 0.230¢ per kWh for transmission charges that were utilized by Edison witnesses Alongi/Kelly in ComEd Exhibit 13 – Attachment E. This is the same figure used by Edison for transmission costs in the derivation of the class and custom CTC derivations.

It should be observed at this point that the transmission charge of 0.230¢ per kWh used in the proposed delivery services tariffs analysis by Edison does not vary by class, as do the current

PPO transmission charges. More importantly, in all cases (except for RCDS Class 10), this assumed transmission cost is lower than the current transmission charges assigned to customers who choose to be served by the PPO. Table 3 illustrates these differences.

AES NewEnergy's concern is that if Edison's assumption of decreasing transmission charges does not materialize as suggested in Edison's calculations, then the effect of increasing delivery services tariffs will have been understated in this proceeding since the assumed lower transmission charges tend to "shield" or "lessen" the effect of the proposed increases in the delivery charges included in Edison's figures.

Baseline Results

The baseline set of comparisons is between the current cost components of the PPO as compared to those same cost components in the proposed delivery services tariffs. Table 4A (and its corresponding summary line on Table 6) shows this comparison.

Estimated Annual Savings Increases/(Decreases)

These amounts were estimated by multiplying the total annual kWh in each respective sub-class by the cost increase in cents per kWh for the sample customer account selected to represent that sub-class. For example, the specific customer account selected in sub-class 6C would experience an increase in total costs of 0.26889¢ per kWh. Sub-class 6C in its entirety utilizes kWh of annual energy consumption. Therefore, the total increased cost assumed for that portion of AES NewEnergy's customer base for sub-class 6C is X 0.26889¢ = $.

The results of the initial run indicate that (%) of AES NewEnergy's present customer accounts, excluding the HVDS-eligible accounts, would be adversely affected (savings would diminish under the proposed delivery services tariffs.) Those same customer accounts comprise % of AES NewEnergy's annual sales volume, excluding the 4 HVDS-eligible accounts. In addition, if a comparison is made between the total amount of annual cost *increases* compared to total amount of estimated annual cost *decreases* across the AES NewEnergy customer base, excluding the HVDS-eligible accounts, there is a **net cost increase of $2,454,482** ($3,753,733 - $1,299,251). The results of this analysis appear to conflict with the assertions in Edison witness Juracek's testimony concerning the ability of CTC decreases to offset the proposed increases in delivery services charges.

The top row of Table 6 summarizes the results of the baseline analysis and includes the following:

- an estimate of how many customer accounts would see savings diminish compared to bundled rates under the proposed delivery services tariffs;
- the proportion of load these accounts represent of AES NewEnergy's customer base, excluding the HVDS-eligible accounts;
- the estimated dollar increase in annual cost; and
- how many of these customer accounts would be expected to become more economically served under bundled rates as a consequence.

Transmission Charge Sensitivity Analysis

As Edison doesn't adequately defend or justify its assumption that transmission charges will decrease, a more reasonable assumption is that transmission charges will remain the same. Table 4A shows that in all sub-classes, except those in RCDS Class 10, Edison's estimated transmission charge of 0.230¢ per kWh for each respective sub-class, results in a presumed decrease in costs due to lower transmission charges than are currently in effect. In fact, if one considers the customer account representative of the 3D-IRMA sub-class, the result of Edison's assumed decrease in transmission rates resulted in this group being considered to have a savings *increase* rather than a savings *decrease*. In many other sub-classes, the presumed decrease in transmission charges tended to "shield" or "lessen" the total effect of the increase in delivery services charges in the proposed tariffs.

To examine the more reasonable assumption that transmission charges remain at their current level, the analysis in Table 4B (and its corresponding summary line on Table 6) was produced. This analysis was performed in a similar manner except that transmission charges were assumed to remain unchanged from their present levels. The fact that the CTC would have been further reduced in the cases where the CTC had enough "room" to absorb this change was also taken into account. For example, consider the customer account representative of sub-class 5B as listed on Tables 4A and 4B. One can see that if that customer account's transmission cost does not decrease by $614 (Table 4A) that the expected CTC for this customer account will improve from a decrease of $1,540 (Table 4A) to a decrease of $1,824 (Table 4B). However, since the customer's CTC cannot go below zero, this decrease is not sufficient to prevent an additional increase in total annual cost under the proposed delivery services tariffs should transmission charges remain unchanged. In this example the customer account would experience a total additional annual increase in cost of $330. In other words, the CTC can only "absorb" *some* of the cost should transmission charges remain level rather than decrease as Edison's testimony asserts.

In the case of customer accounts in classes that have zero or near zero CTC's (RCDS classes 6 and above), the "level" transmission charge cannot be offset by a corresponding decrease in CTC since the CTC is already near or at the minimum. Therefore, if transmission costs remain level, delivery services customers will experience even greater savings reductions. Let me emphasize that this testimony is not suggesting that there will be an increase in transmission charges relative to present day costs, this analysis simply studies the impact of this filing if Edison's assumption that transmission costs will decline does not materialize and instead those costs remain where they are today. Should transmission charges actually *increase* from present day levels, this would have an even further detrimental effect on the competitive market in which AES NewEnergy operates.

Table 4B (and its corresponding summary line in Table 6) demonstrates the effects should transmission charges remain unchanged while adjusting the corresponding CTC's accordingly. One difference found in this analysis is that all the IRMA customers represented by the customer account in sub-class 3D move from experiencing an increase in annual savings to a decrease in annual savings when this difference is taken into account. The other significant difference found should transmission charges remain level is that the **total increased cost** for the proposed delivery services charges on the AES NewEnergy customer base, excluding the 4 HVDS-eligible accounts, would **grow by over $767,000 annually** to $3,222,288 ($4,261,534 - $1,039,247.) (*See* Chart C and Table 6.)

<u>Market Value Sensitivity Analysis</u>

In order to assess the impacts of increasing MVEC's in combination with the proposed increases in delivery services tariffs, the analyses provided in Tables 5A and 5B and 5C were produced. Each of these tables also has a corresponding summary line shown in Table 6. Tables 5A and 5B display the effect of a 5% increase in MVEC's for both the present and proposed delivery services tariffs respectively, along with the corresponding effects on CTC's. Likewise, Table 5C shows the same +5% MVEC scenario utilizing the proposed delivery services tariffs and level transmission charges rather than decreasing ones.

Should MVEC's rise as little as 5% from their current levels the effects on AES NewEnergy's customer base would be harmful even if the delivery services tariffs remain unchanged. However, the effects of an increase in MVEC's of 5% are even more pronounced if considered in *combination* with the proposed increase in delivery services tariffs.

For example, Table 5A (and its corresponding summary line in Table 6) indicate that should MVEC's rise by 5% from current levels, than more than half of AES NewEnergy's customer accounts, excluding the 4 HVDS-eligible accounts, would experience an **increase in cost of approximately $4.7 M** ($4,705,290 - $9,591.) On average, those customer accounts that would see this increase would see total annual costs rise by 1.7%. In contrast, Table 5B (and its corresponding summary line in Table 6) demonstrates the effects of a 5% increase in market values in combination with the proposed increase in delivery services tariffs. These results indicate a **88.5% *larger* annual cost increase of $8.857M** ($9,110,815-$253,640.) due to a 5% increase in MVECs based upon the rates in the current delivery services tariffs. On average, those customer accounts that would see this increase would see total annual costs rise by 4.9%. Table 5C (and its corresponding summary line in Table 6) demonstrates the effects of a 5% increase in market values in combination with the proposed rate changes in the delivery services tariffs while keeping transmission charges level. These results indicate a **112.7% *larger* annual cost increase of approximately $10M** ($10,069,604 - $77,314.) On average, those customer accounts that would see this increase would see total annual costs rise by 5.7%. Finally, the analysis indicates that many more customers representing a much large share of AES NewEnergy's customer base and sales volume would become more economically served under bundled rates should a 5% MVEC increase occur in combination with the proposed increase in delivery services tariffs. (*See* Table 6 and Charts D and E.)